CrossMark

Moving Toward Demand-Based Residential Rates

The widespread use of automated metering infrastructure in the electricity distribution industry is generating increasing discussion of residential demand charges. An analysis of six types of residential rate designs shows that designing residential rates with seasonal consumption charges might make significant progress toward a more efficient rate design. Seasonal usage rates are understandable to customers, avoid many of the problems with demand-based rates, do not require significant implementation expenditures, and may avoid the extreme bill impacts of some demand-based rate options.

Scott J. Rubin

Scott J. Rubin *is a consultant, researcher, and attorney who has worked exclusively on issues affecting the public utility industries for more than 30 years. His consulting clients include public advocates, consumer groups, government-owned utilities, research foundations, and the staffs of utility regulatory commissions. He has testified as an expert witness on rate design, cost-of-service studies, and various policy matters in more than 150 cases throughout the U.S. and Canada; testified as an expert before federal, state, and local legislative committees; and appeared as lead counsel before regulatory commissions in more than a dozen jurisdictions. Mr. Rubin received his bachelor's degree with distinction in Political Science from Pennsylvania State University and his law degree with honors from George Washington University.*

I. Background

The widespread use of automated metering infrastructure (AMI) in the electricity distribution industry is generating increasing discussion of residential demand charges. Conferences are being held where pro-demand-charge consultants (Ryan Hledik, 2015) square off against anti-demand-charge consultants (Barbara Alexander, 2015); interest groups are posting blogs about the desirability of residential demand charges (Rocky Mt. Institute, 2015); and articles are being published in this *Journal* to try to elucidate points on both sides of the issue (Blank and Gegax, 2014; Hledik, 2014).

 1040-6190/ http://dx.doi.org/10.1016/j.tej.2015.09.021

Both sides make valid points. On the one hand, every electricity distribution cost-of-service study (COSS) recognizes that a substantial portion of distribution costs are demand-related. Most utilities, however, have residential rates that contain a customer charge and one or more rates based on energy consumption (rates per kilowatt-hour). Residential demand charges are rare. Where they exist, they are nearly always optional. This means that most residential customers continue to pay demand-related costs through a combination of a flat-rate customer charge and per-kWh charges, rates that may not precisely mirror a customer's demand.

On the other side are those who suggest that residential demand charges are fraught with problems, not the least of which are the need for substantial consumer education and difficulties with tariff administration (including reprogramming utility billing systems and training customer service personnel). Those on the ''anti'' side of the debate also note that there are important rate design concerns other than strict adherence to the results of a COSS. These include understandability, efficiency, gradualism, revenue stability, and affordability.

With AMI the industry has an unprecedented opportunity to better understand the relationship between peak demand and energy consumption on a very granular level – that is, that of the individual customer. The challenge will be to use this information to move toward a residential rate design that is more efficient (that is, improves the collection of demand-related costs from residential customers who cause the demand), yet remains understandable, affordable, and easy to administer.

Any potential rate design must represent a compromise involving a series of trade-offs.

II. Advantages and Disadvantages of Different Rate Designs

Before discussing any specific analyses, it is worth remembering that there is no ''perfect'' rate design. The rate design process involves developing averages and groupings for thousands, or even millions, of customers. No rate design will exactly capture the actual cost to serve an individual residential customer, but the goal is to have a rate design that treats all customers fairly within the confines of the averaging and grouping process.

Thus, any potential rate design must represent a compromise involving a series of trade-offs. Prof. Bonbright taught that among the factors to be evaluated in a rate design are fairness (including relationship of the rates to cost), encouraging the wise use of the service, understandability, ease of administration, non-discrimination, revenue stability, and gradualism (Bonbright, 1961).

Billing based on annual demand has a certain theoretical appeal, but the annual demand is not known until the end of the peak season. A summer-peaking utility might experience its peak in July or August, or even in September during an unusual weather event. Similarly, a winter-peaking utility could reach its peak in December, January, or February. Moreover, a utility whose peak fluctuates (winter peaking some years, summer peaking in others) might not know its annual peak until an entire year passes. In any event, billing based on the annual peak always will be based on some event in the past, often many months before, that the customer can no longer control. When a customer moves during the year or a new home is added to the service territory, there also could be a serious question about the fairness of the billing determinant that will be used for the new account.

Further, the customer's ability to control its peak-period usage might be limited, or simply the

 1040-6190/, http://dx.doi.org/10.1016/j.tej.2015.09.021

result of luck (good or bad). For instance, if a customer happens to be on vacation during the peak day, her contribution to the annual peak might be unusually low compared to her normal seasonal consumption. Similarly, if a customer happens to have the bad luck of having visitors on the peak day, her contribution to the peak might be unusually high compared to her normal seasonal usage.

Other events also could hamper a customer's ability to control consumption during the precise peak hour, especially because the time of the peak is not knowable when energy is being consumed. These might include appliance cycling during the day (how the refrigerator was cycling during the peak hour), whether the customer has a medical device (such as an oxygen concentrator) that was required to work during the peak hour, whether the peak hour occurred during the work day or after the customer returned home from work, and so on.

Rates based on billing (that is, monthly) demand would eliminate some of the temporal shift involved when annual demand is used, but there is a question about the relationship between a customer's monthly peak demands and his contribution to the annual system peak. This is particularly the case for customers who peak off-season, such as space-heating customers in a summer-peaking utility.

Similarly, billing based on annual energy consumption has some advantages (it is easy to understand and administer, and it spreads the utility's revenues throughout the year), but it may not be fair to consumers who use electricity efficiently (that is, high-load-factor customers who control their peak usage). Such a rate also can send the incorrect price signal that the cost of electricity distribution is the same throughout the year, regardless of the time of day or season of consumption.

From a utility's perspective, having most distribution costs collected in the peak season could create concerns with revenue stability.

Collecting demand costs partially through customer charges also can be problematic. Implicitly, this type of rate design assumes that all customers contribute equally to peak demand, which is rarely the case. It also assumes that there are no differences in distribution facilities based on a customer's peak demand. This ignores the fact that transformers and other facilities might be sized differently depending on the expected demands from connected customers. For example, why should a customer in an apartment without air conditioning pay the same amount for demand-related costs as a customer in a large, air-conditioned home where the thermostat is set to 70 °F? Per-customer billing of demand-related costs also fails to send any price signal to a customer about the longer-term costs the customer's energy usage patterns cause to the system.

Seasonal billing also can create problems, both for the utility and for customers. For example, high summer charges essentially give space-heating customers a ''free ride'' on the distribution network. While heating customers may not ''cause'' the system peak, heating customers certainly use wires, poles, transformers, and other distribution facilities that were sized to meet summer peak demands. Setting a non-summer distribution charge very low, therefore, could be unfair to customers.

Finally, from a utility's perspective, having most distribution costs collected in the peak season could create concerns with revenue stability, particularly if weather happens to be unusual (a summer that is much cooler than normal, for example). Such seasonal pricing certainly would change the cash flows of electric distribution utilities, making the cash-flow patterns similar to those experienced by natural gas distribution utilities (very high

 1040-6190/ http://dx.doi.org/10.1016/j.tej.2015.09.021

peak-season revenues) that may require a utility to have a significant line of credit to provide adequate off-season cash flows.

III. Previous Research

In 2014, Blank and Gegax (Blank and Gegax, 2014), working with a small data set (43 households), used linear regression analysis to show that annual energy consumption (kWh) was positively but somewhat weakly correlated with a customer's contribution to peak demand (expressed in kilowatts). Their regression analysis showed that while the result was statistically significant ($\rho < 0.001$) annual kWh explained only 38 percent of the variability in peak demand (kW).

That study also posited that a regression through the origin (that is, an intercept equal to zero) might do a better job of explaining the relationship between kWh and kW. Given the different measurements involved in linear regression analyses with and without an intercept term, Eisenhauer explains that the *R*-squared cannot be used to compare results; rather, results using the two approaches must be evaluated by comparing the standard errors of the analyses (the lower the standard error, the closer the correlation between the variables) (Eisenhauer, 2003). On this basis, the analyses of Blank and Gegax show that the regression with an intercept term is superior (a standard error of 1.96 compared to the regression without an intercept's standard error of 3.06).

Blank and Gegax also suggested that a rate that divided demand charge recovery between the customer charge and the kWh charge might enhance fairness. They did not develop any analyses, however, that would evaluate this hypothesis.

Blank and Gegax suggested that a rate that divided demand charge recovery between the customer charge and the kWh charge might enhance fairness.

IV. Methods

This article expands on the Blank and Gegax approach to evaluate the ability of different residential rate designs. Rate designs are compared for their ability to collect demand-related costs in a manner that might be fairer to customers and consistent with other important rate design principles and goals.

In particular, linear regression analysis is used on a data set containing monthly energy consumption and annual contribution to the system peak demand for 77,675 residential accounts. The data set contains data for a portion of the service area of an electric distribution utility in U.S. Department of Energy climate zone 5 (U.S. Department of Energy, 2013). Some customers in the data set use electricity for space heating in the winter, but most do not. Many (but not all) non-heating customers have summer peak usage evidencing energy usage for air conditioning or other seasonal space cooling. Prior to developing the final data set, some outliers were eliminated (such as accounts with highly atypical usage or demand profiles, those with missing data, etc.).

Hledik (2014) notes that some residential demand charges are developed using billing demand (that is, each customer's maximum demand in each billing period), rather than contribution to annual peak demand. In order to evaluate a rate design using billing demand, it is necessary to have the monthly peak demand for each customer. The data set does not contain those monthly demands, so monthly demands were estimated for each customer using the base, low, and high usage load profiles developed by the U.S. Department of Energy (DOE) for a city within the utility's service area.

Specifically, the ''low'' load profile was used for accounts with annual usage less than 7,500 kWh; the ''base'' profile was used for accounts using between 7,500 and 12,500 kWh during the year; and

  http://dx.doi.org/10.1016/j.tej.2015.09.021

the ''high'' profile was used for accounts using more than 12,500 kWh in the year. From each load profile, the peak demand was determined for each month. From that monthly peak demand, a monthly load factor (ratio of average demand to peak demand) was calculated for each month. The July load factor from the applicable load profile was then compared to the actual July load factor (July was the month when the peak occurred in the data set) for each customer to calibrate the results. For example, if a customer had a load factor in July of 0.50 but the applicable DOE load profile had a July load factor of 0.45, the actual load factor for the month was 11 percent higher than the profile. It was assumed, therefore, that the load factor would be 11 percent higher than the applicable DOE profile in all other months. The monthly load factor was then used to calculate the monthly billing demand. The following equation shows the calculation of May billing demand for a customer in the ''base'' group (using between 7,500 and 12,500 kWh in the year).

$$kW_{May} = \frac{kWh_{May}/744}{BLF_{May} \times [(kWh_{Jul}/744)/(kW_{Annual}/BLF_{Jul})]}$$

where kW = Peak kW demand in a period (month or Annual); kWh = kWh consumption in a period; BLF = Load factor calculated from DOE Base profile in a period; 744 = Number of hours in a 31-day month.

Illustrative rates were then calculated for six different rate design options, as described in Table 1. The rates are based on the customer cost ($13.25 per month per customer) and demand charge ($4.93 per kW per month based on annual peak demand) used by Blank and Gegax. Applying those rates to the customers in the data set produces revenues of approximately $27.7 million. All other rate design options were designed to collect the same amount of revenues.

For purposes of these analyses, it is assumed that the existing rate design is the All kWh design. Thus, the existing rate has a customer charge that collects customer-related costs of $13.25 per month. All other costs (to simplify, it is assumed that all other distribution costs are demand-related) are collected through a flat charge of 1.52¢ per kWh throughout the year.

The second assumption is that the Annual Demand rate represents the cost to serve each customer. That is, this rate collects all customer-related costs in an equal amount per customer and all demand-related costs based solely on each customer's contribution to the annual peak demand. This also makes the

Table 1: Rate Design Options.

Option	Description	Customer Charge (per month)	Demand Charge (per kW per month)	Summer Energy (per kWh)	Non-Summer Energy (per kWh)
Annual Demand	Per kW charge based on annual peak	$13.25	$4.93	– 0 –	– 0 –
Billing Demand	Per kW charge based on monthly peak	$13.25	$5.55	– 0 –	– 0 –
All kWh	All demand costs per kWh	$13.25	– 0 –	1.52¢	1.52¢
Split	Demand costs 60% per kWh; 40% in customer charge	$19.84	– 0 –	0.91¢	0.91¢
All Summer	All demand costs per summer (Jun–Sep) kWh	$13.25	– 0 –	4.79¢	– 0 –
Seasonal	Summer kWh charge is 2 times non-summer charge	$13.25	– 0 –	2.31¢	1.15¢

  http://dx.doi.org/10.1016/j.tej.2015.09.021

simplifying assumption that all demand-related costs are allocated to customer classes based solely on a single coincident peak (that is, each class's contribution to the single hour of the year with the highest system demand).

Thus, the assumed cost to serve each customer (the Annual Demand rate) can be compared to the charges under other rate designs to assess the relationship between the cost of service and revenues for each customer. Rather than comparing demand (measured in kW) against charges (measured in dollars per year), the analyses compare the customer-specific cost of service (in dollars per year) against charges under other rate design options (also in dollars per year for each customer). Because of the existence of a fixed customer charge, bills will never approach zero, which avoids one of the analytical issues raised by Blank and Gegax in their analyses that compared demand (kW) to energy (kWh).

V. Results

Initially, the characteristics of the cost of service are examined. The data show that the cost to serve customers varies from a low of \$159.35 per year (a customer with almost no contribution to peak demand) to \$750.48 per year (the highest-demand customer), with an average of \$356.79 per year (standard deviation of 103.78).

Next, the existing rate (All kWh) is compared to the cost of service. While the cost of service indicated a maximum cost of \$750.48, the existing rates result in a maximum annual bill that is substantially higher: \$919.00. While the average annual bill is essentially the same as the cost of service (\$356.75 versus \$356.79), the existing rates' standard deviation is higher (127.77 versus 103.78), providing an initial

indication that there is a meaningful difference between revenues and costs for many customers.

A linear regression analysis provides further evidence that the existing rate does not ideally track the cost of service for many customers. The analysis shows that the existing rate is positively but modestly correlated with the cost of service, and the relationship is statistically significant ($\rho < 0.001$). Specifically, both the intercept (169.200) and slope (0.526) are positive, indicating that the relationship is logical (customers with higher costs pay higher rates). The R-squared, however, is 0.419, which indicates that there is a substantial unexplained variance between the cost of service and customers' annual bills.

The next stage in the analysis is to evaluate each rate design option in two ways. First, the option is compared to the cost of service with a linear regression analysis. Second, the magnitude of rate change (compared to the existing All kWh rate) is described to indicate whether this type of rate design change might create unacceptable customer impacts. The results of these analyses are shown in Tables 2 and 3.

Several points are noteworthy in these results. First, to move immediately to rates based on annual demand (even if other obstacles could be overcome) would result in dramatic rate changes, ranging from a 76 percent decrease to a 162 percent increase. Ten percent of customers would experience annual bill decreases of 29 percent or less, while another 10 percent of customers would face annual bill increases of 32 percent or more, as shown in **Fig. 1**. It is unlikely that a revenue-neutral rate design change having changes of this magnitude would be consistent with the rate design criteria of public acceptability and gradualism. The difference from existing (kWh-based) rates is simply too severe.

Interestingly, adopting a rate design based on billing demand

 1040-6190/, http://dx.doi.org/10.1016/j.tej.2015.09.021

Table 2: Results of Linear Regression Analyses Compared to Cost (All Demand).

Option	Intercept	Slope	*R*-squared	Significance
All kWh	169.200	0.526	0.419	$\rho < 0.001$
Billing Demand	178.876	0.499	0.426	$\rho < 0.001$
Split	43.695	0.878	0.419	$\rho < 0.001$
All Summer	60.580	0.830	0.846	$\rho < 0.001$
Seasonal	125.856	0.648	0.550	$\rho < 0.001$

Table 3: Bill Changes from Rate Design Options Compared to Existing Bills (All kWh).

Option	Average % Change	Min/Max % Change	10th/90th Percentile	% Bills Increased
Annual Demand	4.4%	−76%/+162%	−29%/+32%	62%
Billing Demand	0.6%	−40%/+183%	−14%/+16%	43%
Split	4.6%	−25%/+49%	−14%/+24%	60%
All Summer	3.0%	−76%/+74%	−26%/+26%	63%
Seasonal	0.7%	−19%/+18%	−6%/+6%	61%

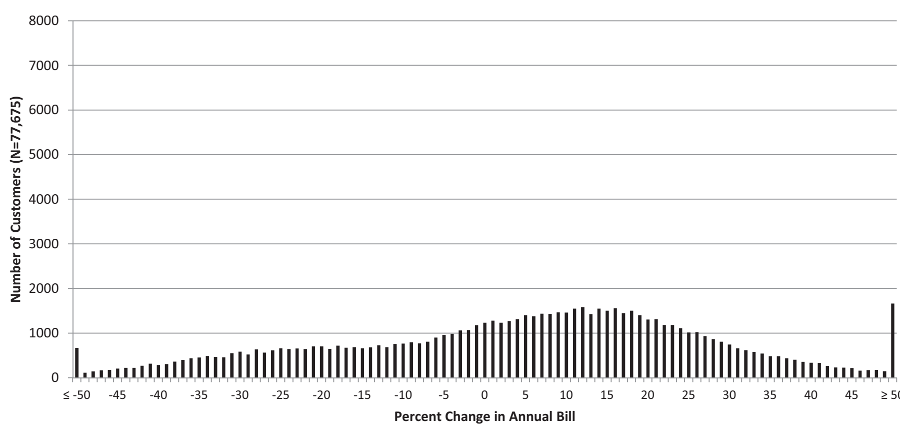


Fig. 1: Distribution of Rate Increases Required to Move from All kWh Rates to Rates Based on Annual Demand

(that is, the customer's peak demand in each billing month) would make almost no progress toward aligning rates with the cost of service. Specifically, this option (Billing Demand) has an *R*-squared of just 0.426 (compared to existing rates' *R*-squared of 0.419) when compared to the cost of service. While this option would have a less severe rate impact than moving to the Annual Demand option, there are still sizeable rate dislocations, with some customers experiencing increases even higher than those experienced under the Annual Demand option (as high as 183 percent). Most customers, however, would experience increases in the range of ±15% (Fig. 2), which is somewhat more acceptable than the ±30% range under the Annual Demand option. Further, this is the only rate design option evaluated that has more customers receiving annual bill decreases than increases (43 percent receive increases, compared to the other options where more than 60 percent of customers receive increases).

It also is interesting to note that the Split option that collects 60 percent of demand-related costs through a kWh charge and 40 percent through the customer charge, does nothing to better align costs and revenues. The *R*-squared under this option is identical to the *R*-squared of existing rates at 0.419. In this

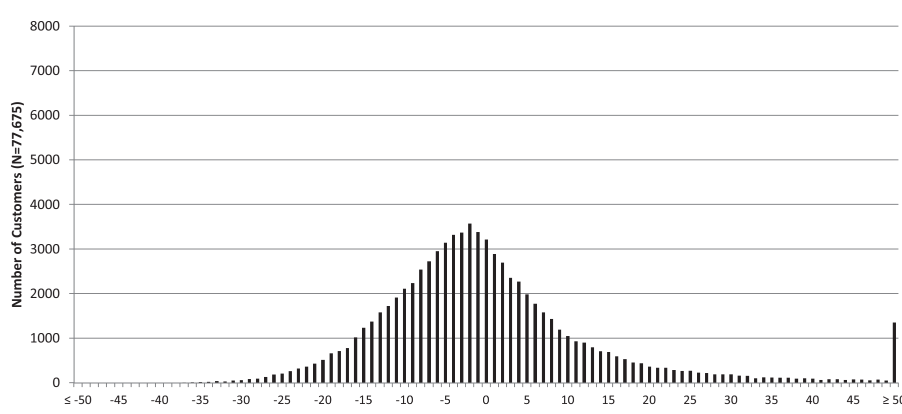


Fig. 2: Distribution of Rate Increases Required to Move from All kWh Rates to Rates Based on Billing Demand

  http://dx.doi.org/10.1016/j.tej.2015.09.021

example, this option represents a classic case of a rate design that creates winners and losers but does nothing to improve the overall efficiency of the rate design (that is, the rate design's ability to more closely track the cost of service).

The last two options evaluated represent cases that may achieve some of the benefits of demand-based rates without using a kW billing determinant. The rate design that collects all demand-related costs through peak-season (summer) kWh charges comes much closer to tracking the cost of service, with an *R*-squared of 0.846. This type of rate could avoid the educational and implementation problems of a demand-based rate while better aligning rates with costs. This type of rate design, however, does have theoretical problems, as discussed above (particularly the problems of revenue stability and off-season customers getting the free use of the distribution network). Moving to this type of rate design also would create significant annual bill changes for customers. Most customers would experience increases in the range of ±26%, with the highest and lowest increases of approximately ±75% (**Fig. 3**).

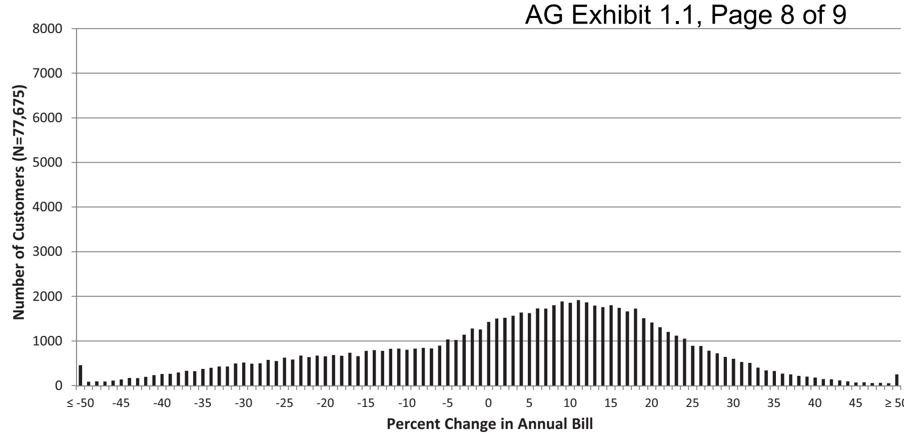


Fig. 3: Distribution of Rate Increases Required to Move from All kWh Rates to Rates Based on Summer kWh

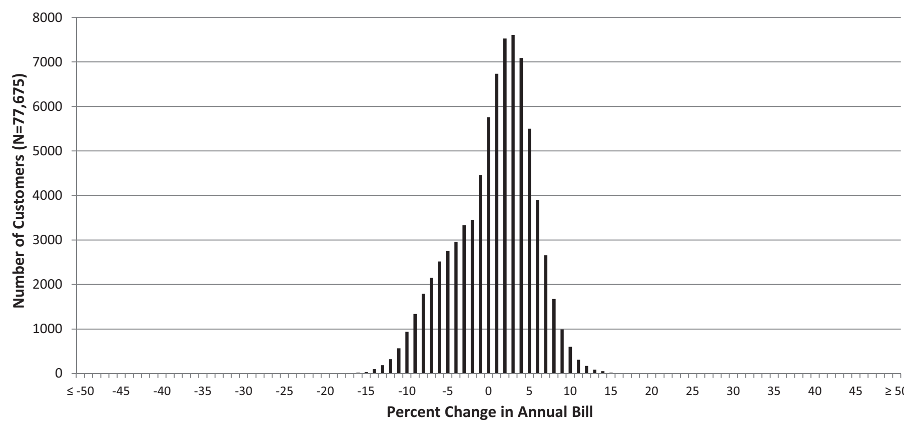


Fig. 4: Distribution of Rate Increases Required to Move from All kWh Rates to Seasonal kWh Rates

The final option evaluated has a summer kWh charge that is double the non-summer kWh charge. This might represent an incremental change in the rate design that does not involve the issues associated with demand-based billing, but moves closer toward cost-based rates in a gradual manner that considers customer impacts. This type of rate design makes meaningful movement toward tracking the cost of service (*R*-squared of 0.550 compared to the existing rate design's 0.419), but without the drastic changes in annual bills that the other rate design options would engender. Under this option, most customers would see bills change within the range of ±6%, with no customer experiencing a change outside the range of ±19%, as shown in **Fig. 4**.

VI. Conclusion

The illustrative rate design options evaluated in this article contain some important results. For example, shifting costs between consumption and customer charges may do nothing to improve the efficiency of the

  http://dx.doi.org/10.1016/j.tej.2015.09.021

rate design, even though customers experience dramatic changes in their annual bills. Similarly, while one might expect monthly billing demands to be closely correlated with annual peak demand, that is not the case in this data set. In fact, using monthly billing demands does very little to improve the efficiency of the rate design compared to a simple kWh-based rate design. Once again, while winners and losers are created, the overall rate design is no better at tracking the cost of serving customers than a consumption-based design.

From these examples, it appears that designing residential electric distribution rates with seasonal consumption charges (higher peak-season charges) might make significant progress toward a more efficient rate design. Seasonal kWh rates are understandable to customers, avoid many of the problems with demand-based rates (such as the ''lucky'' customer who happens to be away from home on the day of the annual peak), do not require significant implementation expenditures, and may avoid the extreme bill impacts of some demand-based rate options.

There are a limitless number of rate design options available to utilities and regulators. With the wide-scale deployment of AMI, data will be available that will allow analysts to develop rate design options that improve the efficiency of the rate design (that is, its ability to have a customer's revenues collect the cost of serving the customer) while also evaluating the impacts of the rate design change on customers. This article has highlighted some of the statistical and comparative techniques that should be helpful in the development of such rates. It is hoped that analysts and researchers will further explore these topics with more extensive data sets, other rate design options, and different statistical techniques for evaluating the ability to improve rate design efficiency while remaining sensitive to other longstanding rate design principles and goals.■

References

Blank, L., Gegax, D., 2014. Residential winners and losers behind the energy versus customer charge debate. Electricity J. 27 (May (4)) 31–39, http://dx.doi.org/10.1016/j.tej/2014.07.003.

Bonbright, J.C., 1961. Principles of Public Utility Regulation. Columbia University Press, New York, NY, pp. 291.

Eisenhauer, J.G., 2003. Regression through the origin. Teach. Stat. 25 (Autumn (3)) 76–80.

Hledik, R., 2014. Rediscovering residential demand charges. Electricity J. 27 (August/September (7)) 82–96, http://dx.doi.org/10.1016/j.tej.2014.07.003.

Presentation by Barbara Alexander, 2015, June. Residential Demand Charges: A Consumer Perspective, http://www.ksg.harvard.edu/hepg/Papers/2015/June%202015/Alexander%20Panel%201.pdf.

Presentation by Ryan Hledik, Brattle Group, Rolling Out Residential Demand Charges, May 2015, http://www.brattle.com/system/publications/pdfs/000/005/170/original/Rolling_Out_Residential_Demand_Charges_Hledik_EUCI.pdf?1431628444.

Rocky Mt. Institute, 2015. Blog post by Matt Lehrman, May 21, 2015: Are Residential Demand Charges the Next Big Thing in Electricity Rate Design? , In: http://blog.rmi.org/blog_2015_05_21_residential_demand_charges_next_big_thing_in_electricity_rate_design.

U.S. Department of Energy, 2013, November. Guide to Determining Climate Regions by County. Prepared by the Pacific Northwest National Laboratory, No. PNNL-17211 Rev. 2.

U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy. Commercial and Residential Hourly Load Profiles for all TMY3 Locations in the United States. http://en.openei.org/datasets/dataset/commercial-and-residential-hourly-load-profiles-for-all-tmy3-locations-in-the-united-states

  http://dx.doi.org/10.1016/j.tej.2015.09.021

Ameren Illinois Company
Ill. Commerce Comm'n Docket No. 16-0387

AG Exhibit 1.2

Comparison of Residential (DS-1) Rate Proposals for Rates Effective 1/1/2017

		Rates			Revenues		
	Billing Units	Present Design	AIC Proposed	AG Proposed	Present Design	AIC Proposed	AG Proposed
Customer charge	12,723,905	11.41	13.04	6.99	$ 145,179,754	$ 165,919,719	$ 88,940,095
Meter charge	12,723,905	4.77	4.77	4.77	60,693,026	60,693,026	60,693,026
Summer all kWh	4,281,306,903	0.04563	0.04301	0.05276	195,356,034	184,139,010	225,881,752
Winter 1st 800 kWh	4,944,693,424	0.02672	0.02517	0.03091	132,122,208	124,457,933	152,840,474
Winter over 800 kWh	2,269,191,196	0.01421	0.01339	0.01641	32,245,207	30,384,470	37,237,428
Total					$ 565,596,229	$ 565,594,158	$ 565,592,774
% of Revenue from fixed charges					36.4%	40.1%	26.5%

Sources:
Billing Units from AIC Ex. 1.4
Present Design calculated using current parameters to produce AIC proposed revenues for DS-1 class
AIC Proposed from Ameren Ex. 1.4
AG Proposed from AIC response to Staff data request CLH 1.02

Ameren Illinois Company
Ill. Commerce Comm'n Docket No. 16-0387

AG Exhibit 1.3

Elements of the Cost of Serving Residential (DS-1) Customers (2015 test year)
(Costs x $1,000)

	Cost	Units	Unit Cost
Customer cost	$ 95,054	12,723,905	$ 7.47
Meter cost	56,099	12,723,905	4.41
Demand - contribution to system coincident peak (CP)	163,185	2,773,198	58.84
Demand - contribution to class non-coincident peak (NCP)	167,630	3,402,401	49.27
Demand - individual customer highest peak demand (Sigma NCP)	53,678	6,601,703	8.13
Total	$ 535,646		

Sources:
Customer and meter costs from AIC response to AG 6.02
Demand costs allocated in proportion to plant
Units are from ECOSS (demand measured at secondary voltage)
Note: Demand unit costs are $ per kW per year; customer and meter unit costs are $ per bill

Ameren Illinois Company AG Exhibit 1.4
Ill. Commerce Comm'n Docket No. 16-0387

Hypothetical Rates and Unit Costs to Illustrate Effects on Load Research Sample

Hypothetical Demand Rates

	Annual	Summer +25%	Summer +50%	Summer +100%
Customer charge	$ 7.50	$ 7.50	$ 7.50	$ 7.50
Meter charge	$ 5.11	$ 5.11	$ 5.11	$ 5.11
Summer rate per kW	$ 6.24	$ 7.16	$ 7.95	$ 9.20
Winter rate per kW	$ 6.24	$ 5.73	$ 5.30	$ 4.60
Revenues from sample	$ 128,447	$ 128,423	$ 128,480	$ 128,378

Hypothetical Energy Rates

	36.4% Fixed	40.0% Fixed	26.4% Fixed	Summer Incline
Customer charge	$ 11.41	$ 14.34	$ 7.50	$ 7.50
Meter charge	$ 4.77	$ 4.77	$ 5.11	$ 5.11
Summer first 800 kWh	$ 0.04563	$ 0.04142	$ 0.05081	$ 0.04664
Summer over 800 kWh	$ 0.04563	$ 0.04142	$ 0.05081	$ 0.05830
Winter first 800 kWh	$ 0.02672	$ 0.02424	$ 0.02977	$ 0.02977
Winter over 800 kWh	$ 0.01421	$ 0.01289	$ 0.01580	$ 0.01580
Revenues from sample	$ 128,422	$ 128,439	$ 128,481	$ 128,485

Hypothetical Unit Cost

Customer cost	$ 7.50	per month
Meter cost	$ 5.11	per month
Cost per kW at CP	$ 160.14	per year
Cost per kW at class NCP	$ 95.31	per year
Cost per kW at Sigma NCP	$ 7.28	per year
Costs from sample	$ 128,415	

Ameren Illinois Company AG Exhibit 1.5
Ill. Commerce Comm'n Docket No. 16-0387

Relationship of Different Rate Designs to Cost of Service
Using 224-Household Load Research Sample and Hypothetical Rates and Costs

	Relationship of Revenues to Costs (number of customers in each range)						
Rate Option	± 5%	± 10%	± 20%	± 30%	± 40%	± 50%	Outside ± 50%
Demand Rate Options							
Annual	23	43	94	124	159	178	46
Summer +25%	25	46	93	127	159	179	45
Summer +50%	26	49	93	129	159	182	42
Summer +100%	25	47	95	131	161	183	41
Energy Rate Options							
36.4% Fixed	23	54	108	150	177	193	31
40.0% Fixed	26	53	99	142	172	190	34
26.4% Fixed	25	55	117	155	180	195	29
Summer Incline	30	55	113	160	181	197	27

Ameren Illinois Company AG Exhibit 1.6
Ill. Commerce Comm'n Docket No. 16-0387

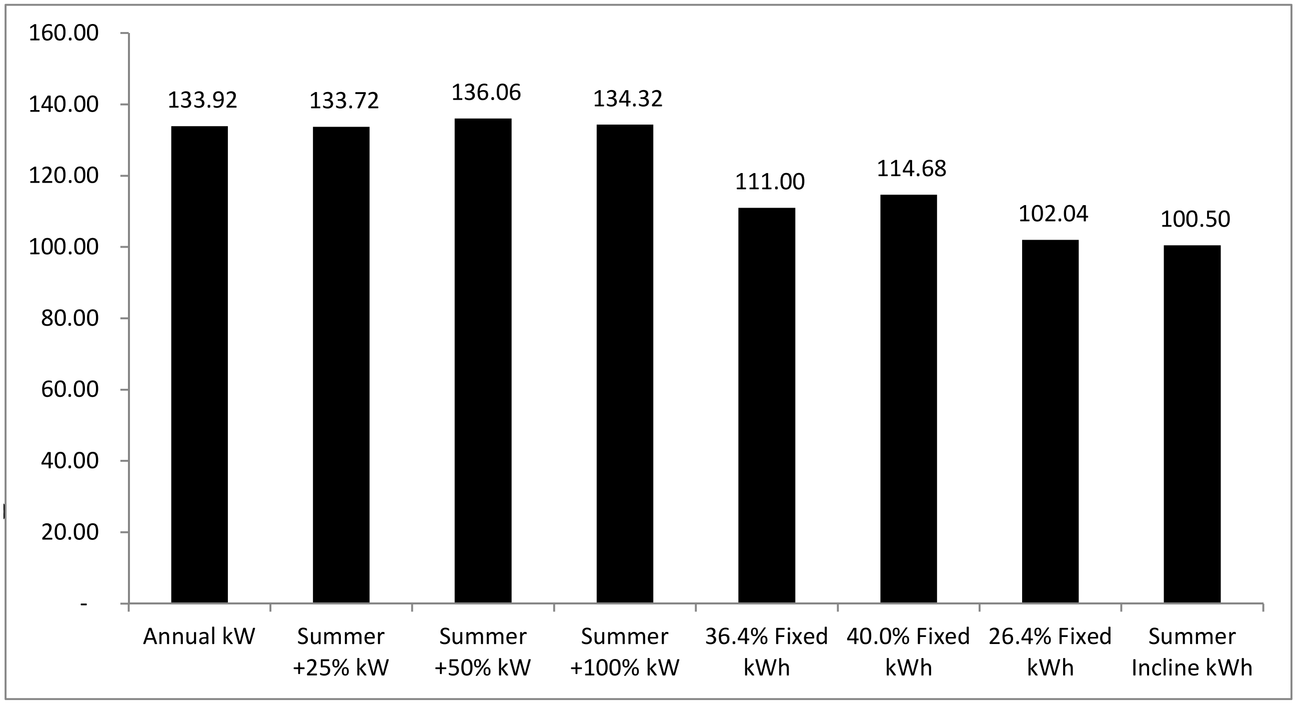
Statistical Measures of Deviation (or Dispersion)
($)
(In each instance, the smaller number means revenues are closer to costs)

Rate Option	Mean of Absolute Deviations	Median of Absolute Deviations	Standard Deviation
Demand Rate Options			
Annual	175.94	133.92	229.99
Summer +25%	173.15	133.72	226.82
Summer +50%	170.96	136.06	224.32
Summer +100%	168.07	134.32	220.63
Energy Rate Options			
36.4% Fixed	136.17	111.00	177.73
40.0% Fixed	140.36	114.68	182.02
26.4% Fixed	132.25	102.04	173.99
Summer Incline	129.31	100.50	170.03

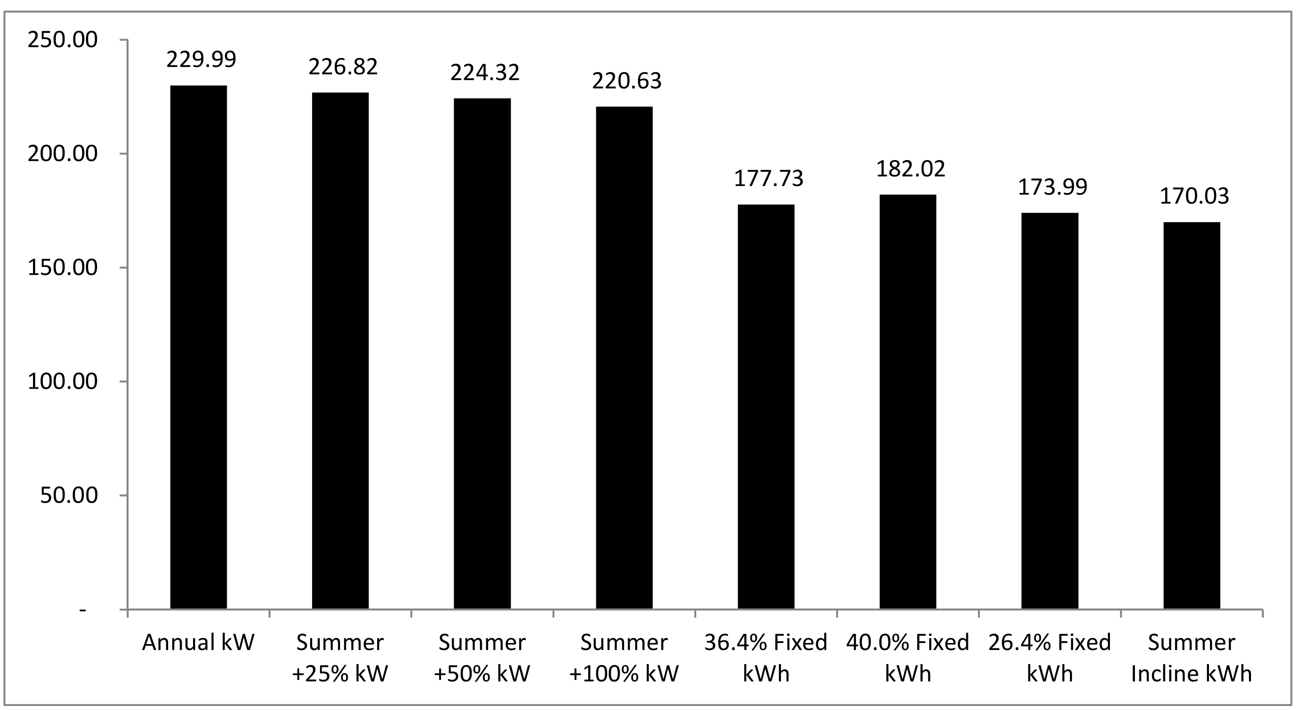
Ameren Illinois Company AG Exhibit 1.7
Ill. Commerce Comm'n Docket No. 16-0387

Graphical Depiction of Statistical Measures of Deviation (or Dispersion)

Median of Absolute Deviations of Cost-Revenue Difference ($)



Standard Deviation of Cost-Revenue Difference ($)



Ameren Illinois Company
Ill. Commerce Comm'n Docket No. 16-0387

AG Exhibit 1.8

Customer Impact of Hypothetical Rate Design Options

Range of Increase in Annual Delivery Service Bill Compared to Present (36.4% Fixed) Rate Design

Rate Option	less than 1%	1-5%	5-10%	10-15%	15-20%	20-25%	25% or more	Lowest	Highest
Demand Rate Options									
Annual	116	26	15	15	12	10	30	-40%	64%
Summer +25%	116	30	12	16	10	14	26	-40%	62%
Summer +50%	113	28	18	16	12	11	26	-40%	60%
Summer +100%	114	23	23	13	13	12	26	-40%	56%
Energy Rate Options									
40.0% Fixed	125	74	20	5	-	-	-	-4%	13%
26.4% Fixed	129	90	5	-	-	-	-	-16%	5%
Summer Incline	138	59	26	1	-	-	-	-17%	10%

Ameren Illinois Company
Ill. Commerce Comm'n Docket No. 16-0387

AG Exhibit 1.9

Customer Impact of Hypothetical Rate Design Options on 27 Likely Space-Heating Customers
Range of Increase in Annual Delivery Service Bill Compared to Present (36.4% Fixed) Rate Design

Rate Option	less than 1%	1-5%	5-10%	10-15%	15-20%	20-25%	25% or more	Lowest	Highest
Demand Rate Options									
Annual	7	3	2	3	1	1	10	-36%	63%
Summer +25%	7	4	4	-	2	3	7	-37%	58%
Summer +50%	9	3	3	-	3	2	7	-37%	55%
Summer +100%	12	2	1	2	1	3	6	-39%	49%
Energy Rate Options									
40.0% Fixed	23	3	1	-	-	-	-	-4%	6%
26.4% Fixed	9	16	2	-	-	-	-	-8%	5%
Summer Incline	17	7	3	-	-	-	-	-8%	7%

Ameren Illinois Company AG Exhibit 1.10
Ill. Commerce Comm'n Docket No. 16-0387

Hypothetical Rate Impact on One Space-Heating Customer in Sample

	kWh	kW	Present	Demand Rate (Summer +100%)	Energy Rate (26.4% Fixed)
January	3,113.36	20.22	$ 70.43	$ 105.65	$ 72.98
February	3,295.69	14.85	73.02	80.94	75.86
March	3,548.28	14.35	76.61	78.62	79.85
April	1,757.64	14.37	51.16	78.72	51.56
May	1,948.39	13.69	53.87	75.61	54.57
June	1,105.68	9.60	66.63	100.98	68.79
July	756.87	6.95	50.72	76.53	51.07
August	707.78	6.52	48.48	72.56	48.58
September	901.12	6.85	57.30	75.61	58.40
October	1,082.29	7.15	41.57	45.50	40.89
November	1,553.46	7.91	48.26	48.98	48.33
December	3,283.21	14.30	72.84	78.39	75.66
Total summer	3,471.44	29.92	$ 223.13	$ 325.68	$ 226.84
Total non-summer	19,582.32	106.85	487.76	592.41	499.70
Total annual	23,053.77	136.76	$ 710.89	$ 918.09	$ 726.54